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Navigating through hydrogen

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Executive summary

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HYDROGEN IS SEEN AS a means to decarbonise sectors with greenhouse gas emissions that are hard to reduce, as a medium for energy storage, and as a fallback in case halted fossil-fuel imports lead to energy shortages. Hydrogen is likely to play at least some role in the European Union's achievement by 2050 of a net-zero greenhouse gas emissions target.

HOWEVER, PRODUCTION OF HYDROGEN in the EU is currently emissions intensive. Hydrogen supply could be decarbonised if produced via electrolysis based on electricity from renewable sources, or produced from natural gas with carbon, capture, and storage. The theoretical production potential of low-carbon hydrogen is virtually unlimited and production volumes will thus depend only on demand and supply cost.

ESTIMATES OF FINAL HYDROGEN demand in 2050 range from levels similar to today's in a low-demand scenario, to ten times today's level in a high-demand scenario. Hydrogen is used as either a chemical feedstock or an energy source. A base level of 2050 demand can be derived from looking at sectors that already consume hydrogen and others that are likely to adopt hydrogen. The use of hydrogen in many sectors has been demonstrated. Whether use will increase depends on the complex interplay between competing energy supplies, public policy, technological and systems innovation, and consumer preferences.

POLICYMAKERS MUST ADDRESS THE need to displace carbon-intensive hydrogen with low-carbon hydrogen, and incentivise the uptake of hydrogen as a means to decarbonise sectors with hard-to-reduce emissions. Certain key principles can be followed without regret: driving down supply costs of low-carbon hydrogen production; accelerating initial deployment with public support to test the economic viability and enable learning; and continued strengthening of climate policies such as the EU emissions trading system to stimulate the growth of hydrogen-based solutions in the areas for which hydrogen is most suitable.

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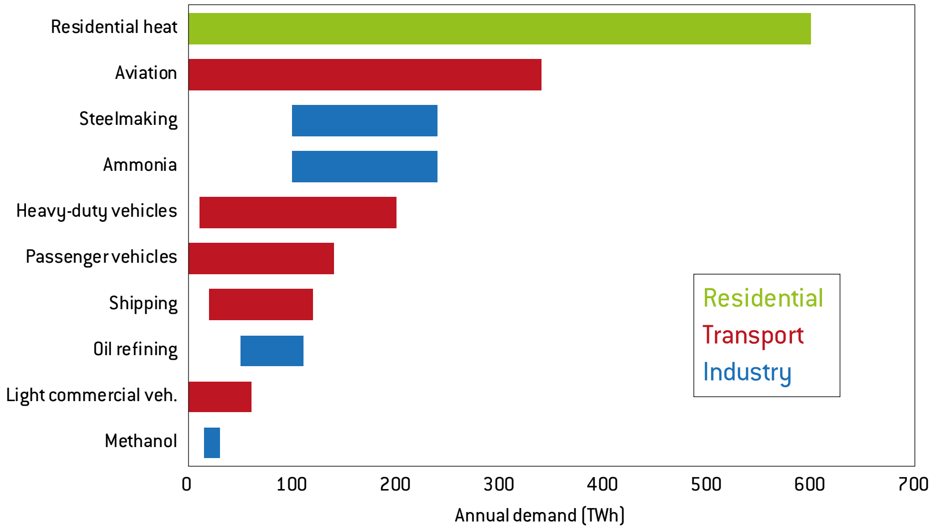
1 Introduction

In the European Union's decarbonisation drive, hydrogen is seen as a solution for sectors with greenhouse gas emissions that are hard to reduce, as a means of energy storage, and as a fallback in case halted fossil-fuel imports lead to energy shortages. The attractiveness of hydrogen comes from the fact that no carbon dioxide is emitted when it is burned or used in a fuel cell to produce electricity. In sectors where it could be applied, hydrogen could displace fossil-fuel consumption and the associated carbon emissions.

Hydrogen is not a new fuel. Its ability to provide useful energy has been understood for well over 100 years. As recently as the early 2000s, a wave of public interest focused on its potential for powering automobiles (Lizza, 2003). Interest in hydrogen is now resurging in the EU, linked to the bloc's much more ambitious decarbonisation targets. On the demand side, hydrogen could be a solution for particularly hard-to-abate sectors, such as steel, providing a valuable argument that full decarbonisation is technically feasible. On the supply side, the potential for large imports of low-carbon hydrogen is attractive when considered against the argument that the EU's clean energy potential might be too limited. Moreover, hydrogen offers one solution to the seasonal storage issue that while renewable electricity generation peaks in summer, demand peaks in winter.

Notwithstanding this technical promise, hydrogen remains prohibitively expensive. Its use today in the European Union is thus far removed from the role optimists see it playing in a net-zero EU in 2050. It is currently used almost exclusively as a chemical feedstock for the production of ammonia and methanol and for crude oil refining. Furthermore, the dominant production route for hydrogen – involving separation of hydrogen from methane – is highly carbon-intensive. But hydrogen can also be produced from electricity via electrolysis. The rapidly falling cost of electricity from renewables is creating excitement about low-cost, low-carbon hydrogen production.

Figure 1: Estimated variation in hydrogen demand in 2050



Source: Bruegel. Note: Horizontal bars represent the range of annual hydrogen demand between our highest and lowest assumptions (see section 3). The European Commission (2018) estimated total final energy demand in 2050 of 10,000 TWh. Some of the uses for hydrogen shown in the figure are as a chemical feedstock, not energy consumption, but the 10,000 TWh figure still provides a sensible order of magnitude. Our higher estimate (2,080 TWh) would see total hydrogen demand of approximately 20 percent of final energy demand in 2050, with the lower estimate (295 TWh) at 3 percent.

The future role hydrogen will play in the sectors where it could be deployed depends upon the extent to which the necessary technologies reach commercial maturity. This will be driven by the complex interplay of capital costs, consumer preferences, policy decisions, and the relative performance of competing clean energy sources. Because of these uncertainties, we estimate that in 2050, hydrogen could meet 20 percent of EU final energy demand – but it may meet only 3 percent (Figure 1). This is in line with more sophisticated modelling studies.

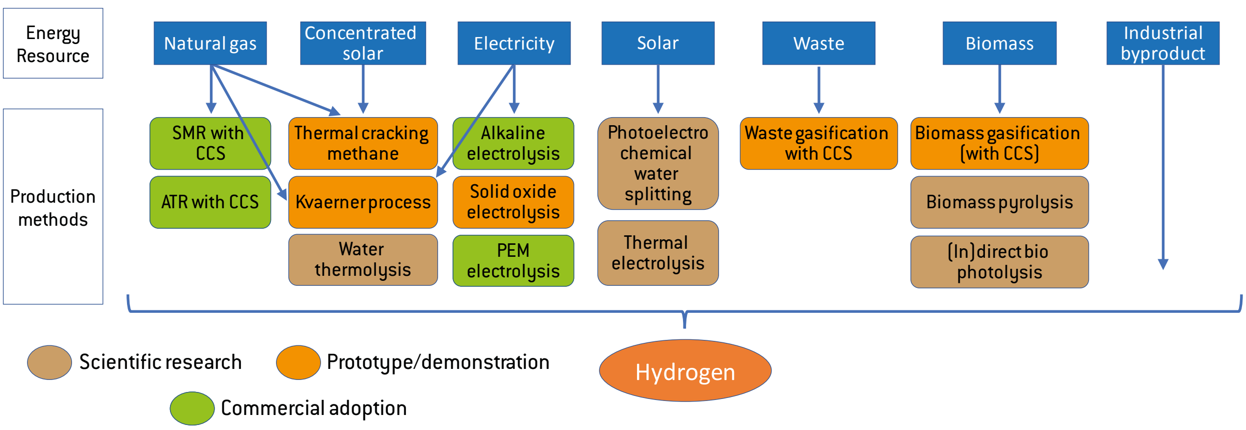
This Policy Contribution examines the gap between 3 percent and 20 percent. Our analysis supports the idea that decarbonisation will be driven mainly by electrification, while hydrogen will emerge to fill the niche for applications where electricity is either too expensive or complex. We first explore the potential for hydrogen to evolve from today's highly polluting chemical feedstock to a key clean energy source in a decarbonised EU in 2050. The first fundamental step is the ability to produce significant volumes of clean hydrogen (section 2). We then examine the main sectors in which hydrogen is currently being consumed or is considered an important pathway for future decarbonisation. To illustrate the uncertainty around future hydrogen demand we assess what 2050 hydrogen demand might be in ten significant sectors (section 3).

The difficulty for policymakers today lies in knowing exactly where the hydrogen niche lies. It could cover whole sectors, such as aviation, or might cover sub-sectors, such as hydrogen fuel cells for heavy vehicles travelling long distances. Or hydrogen might find a temporary niche, for example in heating of buildings. Despite the uncertainty, hydrogen's current use as a chemical feedstock and highly likely adoption in the steel sector mean that at least some clean hydrogen will be required by 2050. Public policy, which we cover in section 4, should therefore focus on stimulating cost reductions for the production of clean hydrogen.

2 Hydrogen supply

Large-scale production of hydrogen can be done using six very different inputs: natural gas, electricity, biomass/waste, solar radiation, coal and oil. At least 16 different production methods generate hydrogen from at least one of these inputs. Production methods differ significantly in their associated greenhouse-gas emissions. For example, for production via electrolysis (electricity is used to split water molecules into hydrogen and oxygen atoms), the origin of the input electricity determines whether the hydrogen is carbon-neutral (eg when produced from renewable or nuclear-generated electricity) or highly polluting (eg electricity from lignite power plants). Figure 2 provides a schematic overview of the low-carbon production pathways for hydrogen.

Figure 2: Low-carbon hydrogen production



Source: Bruegel based on Hanley *et al* (2017), Nikolaidis and Poullikkas (2017), Piebalgs *et al* (2020) and IEA (2020). Notes: SMR = steam methane reforming. CCS = carbon capture and storage. PEM = polymer electrolyte membrane. ATR= autothermal reforming.

The cost-competitiveness of different hydrogen production processes depend on the capital costs of the required installations, their technological efficiency in transforming input fuels into hydrogen, the input fuel and carbon prices.

Hydrogen supply capacity in the EU is currently estimated at 339 terawatt hours per year[1], approximately 3 percent of EU final energy demand (FCH JU, 2019). Of this, over 95 percent is hydrogen produced from fossil fuels, and less than 5 percent is produced via electrolysis (Cihlar *et al*, 2020). Production of fossil hydrogen in Europe is mainly done by separation of hydrogen from a stream of methane, a process that generates significant carbon dioxide emissions. Box 1 compares these emissions to those from electrolysis, which depend on the carbon intensity of electricity.

Box 1: Carbon emissions associated with hydrogen from methane and electrolysis

For hydrogen from methane without CCS, the carbon intensity of production is around 270g CO_2/kWh. For an electrolyser connected to the European electricity grid, average emissions will be 430g CO_2/kWh, based on current average electricity-related emissions of 285g CO_2/kWh. Therefore, electrolytic hydrogen will only result in better emissions performance than SMR when the average emissions intensity of European electricity is reduced to significantly below 200g CO_2/ kWh. Extrapolation of current decarbonisation trends would see this happening around 2025. Production from electrolysis will become even cleaner over time as electricity is further decarbonised.

Very low carbon intensities can already today be achieved in many hours of the year, such as on sunny and windy summer weekends, or in certain EU countries, such as France and Denmark. But making hydrogen production 'low-carbon' by producing it from green electricity has no economic justification because it would only imply that other consumers would consume non-green electricity. To ensure that domestic hydrogen production does not result in increasing emissions, the cap of the EU emissions trading system (which covers hydrogen production from electricity and natural gas) should be tightened enough to meet the EU climate targets.

The EU hydrogen strategy, published in July 2020, aims to set out a vision for *"how the EU can turn clean hydrogen into a viable solution to decarbonise different sectors"* (European Commission, 2020). It is centred on scaling up electrolysis production with renewable electricity input. An alternative option would be to apply carbon capture storage (CCS) technology in the production of hydrogen from methane, capturing up to 90 percent of the CO2 emissions generated[2] (IEA, 2019a). The strategy sees a role for CCS in hydrogen production in the short and medium terms, but not as a long-term priority.

The competitiveness of hydrogen from methane compared to electrolysis depends on the price of the inputs (natural gas or electricity) and the carbon price (Figure 3). Our estimates for methane production use a price of €20/MWh, while the range of electricity prices likely available to industrial producers is the vertical shaded grey area, around €40-€50/MWh[3].

Figure 3 shows that at current natural gas, electricity and carbon prices[4], hydrogen production from methane without CCS is significantly cheaper than hydrogen production from

1 In this paper we transfer all energy units (electricity, hydrogen, natural gas, etc) into terawatt hour (TWh) for easier comparability. One TWh is about 0.03 million tonnes hydrogen or 92 million cubic meters of Russian natural gas.

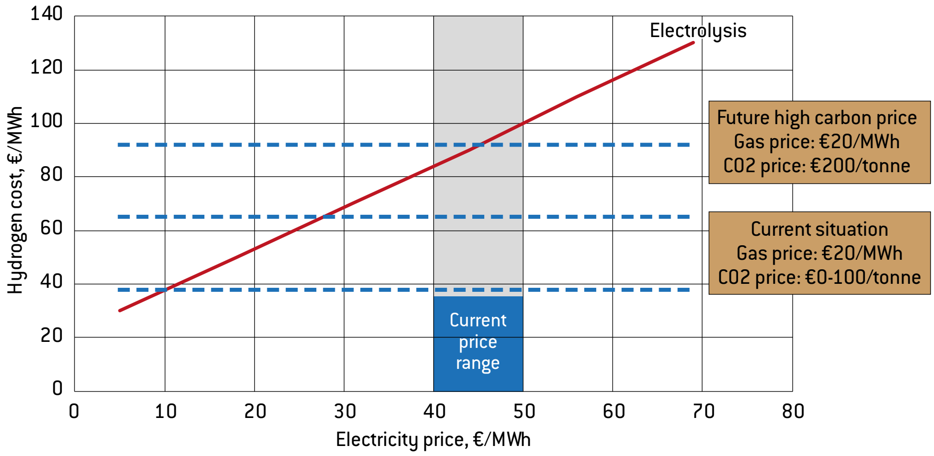
2 90% is a technical maximum. The range of carbon captured is likely to be in the range of 60-90%. Capturing carbon between 60 and 90% is relatively more expensive.

3 See https://www.eex.com/en/market-data/power/futures where futures at the Belgian energy exchange frequently settle at around €50, and https://www.powernext.com/futures-market-data where an index of European natural gas prices stays around €20.

4 In fact, we consider a carbon price of €50 a likely upper bound for the next three years.

electricity[5]. However, if electricity prices drop to about €20/MWh (for example because of cost reductions related to renewables), hydrogen produced from electricity would become cheaper than that produced from methane. On the other hand, increases in the carbon price would also affect the cost. An increase in the carbon price to €200/tonne would mean that electricity at current prices would become competitive with natural gas.

Figure 3: Hydrogen price for different electricity and carbon prices



Source: Bruegel based on IEA. Note: the graph shows the different hydrogen prices for different electricity prices using an electrolyser, where the cost of carbon is already internalised through the carbon price paid by electricity generators. For natural gas production, we assume a gas price of €30/MWh. The dashed lines represent different hydrogen costs for different carbon prices paid for a methane plant without CCS. Calculations based on IEA assumptions: for electrolysis, CAPEX - $900/kWe, efficiency – 64%, Annual OPEX – 1.5% of CAPEX. For natural gas reforming, CAPEX - $910/kWH2, Efficiency – 76%, Annual OPEX = 4.7% of CAPEX, emissions = 8.9kgCO2/kgH2.

Furthermore, the capital costs of electrolysers could fall significantly in the near term, meaning that electrolysis would be competitive even if electricity prices do not drop to €25/MWh. Wood Mackenzie (2020), for example, forecast electrolysis-produced hydrogen becoming cost-competitive with methane-produced hydrogen between 2030 and 2040, depending on the region, because of shifting cost dynamics. Commitments in hydrogen strategies published so far by the EU, its member states and other countries to deploy electrolyser capacity are set to stimulate cost reductions.

Moreover, our analysis is based on average EU values and cost assumptions. Differing tax rates, network costs and wholesale prices drive significant regional electricity price differences. The competitiveness of electricity versus gas will therefore vary between regions.

And we base our analysis on an electrolysis plant behaving as a traditional baseload consumer of electricity, ie demanding electricity with limited flexibility, which is the situation with electrolysers today. However, developments in alternative electrolysis technology[6], the falling capital cost of electrolysers and the increasing variability of electricity prices (because of increasing shares of renewable energy generation) could increase demand for electrolysis as a source of flexible power demand. Therefore, electrolysis could emerge as a significantly more competitive technology by: a) utilising close to zero (or occasionally even negative) electricity prices for a substantial number of hours, and b) providing flexibility services to the grid by consuming excess electricity at times of excess supply and helping to facilitate the over-deployment of renewable electricity sources (see section 3.4).

5 Estimates using IEA data. This illustrative example assumes that the required installations for hydrogen production from methane and from electrolysis are available.

6 The EU is in particular supporting the development of proton electron membrane (PEM) electrolysers. For example the REFHYNE project (https://refhyne.eu/) will install and operate the world's largest hydrogen PEM electrolyser with 10MW capacity. This is important because PEM electrolysers are able to more quickly adjust demand in response to fluctuating electricity supply compared to conventional electrolysers.

2.1 Alternative production pathways

Hydrogen production from natural gas and electricity are the most common methods, but there are others. Table 1 lists them, along with some rough cost estimates.

Table 1: Additional low-carbon hydrogen production methods

Production method	Energy source	Feedstock	Hydrogen cost est. (€/MWh)
Autothermal reforming with CCS	Fossil fuels	Natural gas	50
Methane pyrolysis/thermal cracking	Internally generated steam	Natural gas	54 - 57
Biomass pyrolysis	Internally generated steam	Biomass	42 - 74
Biomass gasification	Internally generated steam	Biomass	60 – 69
Direct bio-photolysis	Solar	Water and algae	72
Indirect bio-photolysis	Solar	Water and algae	48
Dark fermentation		Organic biomass	87
Photo-fermentation	Solar	Organic biomass	96
Solar thermal electrolysis	Solar	Water	172 - 354
PEC process (photo-electrolysis)	Solar	Water	350
Nuclear thermolysis (thermal cracking of water)	Nuclear	Water	73 - 89
Solar thermolysis (thermal cracking of water)	Solar	Water	269 - 284

Source: Kayfeci *et al* (2019). Note: CCS = carbon capture and storage.

In sum, the global technical production potential of hydrogen exceeds demand by several orders of magnitude[7], meaning expansion of supply depends in principle only on the hydrogen production cost and demand at that cost level. National hydrogen production costs can differ depending on the differing availability and cost of inputs and capital, the availability of required infrastructure for transport, hydrogen storage and possibly carbon storage space.

2.2 Hydrogen imports

In optimistic scenarios, hydrogen could contribute a significant share of final energy demand within the EU by 2050. The EU hydrogen strategy works with a projection of 13 percent to 14 percent by 2050 (European Commission, 2020). If hydrogen demand is to reach such levels, imports of hydrogen might also develop. The European Commission hydrogen strategy aims to develop 40 GW of hydrogen capacity in neighbourhood regions by 2030 – the same capacity the EU aims for within its borders. From countries with an abundance of renewable energy resources, green hydrogen could become an attractive export.

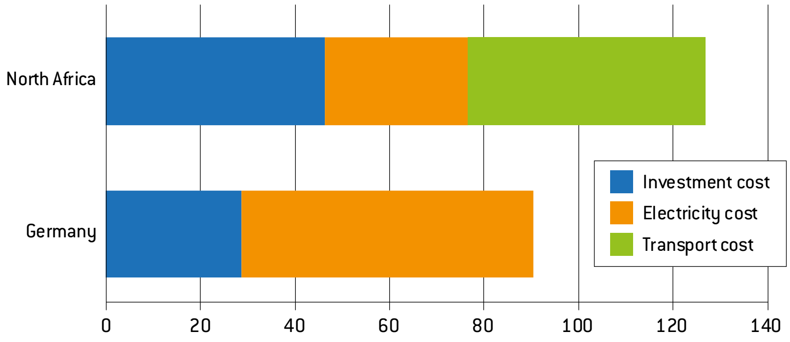
Installing renewables and electrolysers outside the EU and importing the hydrogen into the EU only makes economic sense when the renewables conditions in the exporting countries are significantly better, while capital costs are not substantially higher than in the EU. Furthermore, the cost advantage must exceed the costs of delivery of hydrogen as a gas via pipelines. Alternatively, hydrogen can be transformed into, for example, ammonia, which can be more easily stored in liquid form and transported by ship.

Based on IEA assumptions of current costs it seems hard to make a case for imports of

7 Solar potential of some 600,000 TWh/year from Korfiati *et al* (2016) alone would enable around 12,000 Mt of hydrogen production.

hydrogen from solar energy from North Africa. If deployment of additional wind or solar units in Germany becomes difficult because suitable/acceptable land is already utilised, while investment costs in Africa decline, imports of hydrogen might become competitive. However, consistent international rules would be needed to ensure that significant imports of hydrogen do not directly or indirectly increase net emissions in the producing country, for example through land-use change or replacement of renewable electricity for local populations by fossil fuels.

Figure 4: Import vs domestic hydrogen (€/MWh)



Source: IEA (2019a). Note: Key assumptions: CAPEX electrolyser: $900/kW, electricity price in Germany: $47/MWh, electricity price in North Africa: $23/MWh, interest rate in Germany: 5%, interest rate in North Africa: 10%, transport distance: 3,000Km, pipeline transport cost of $2/Kg.

3 Hydrogen demand

The future evolution of demand for hydrogen in Europe is highly uncertain. Hydrogen has historically had a limited role in influential global energy modelling studies (for example, Quarton *et al*, 2020). In this section, we discuss the most likely sectors for future hydrogen demand, with calculations for high, medium and low hydrogen demand scenarios. We thus provide a broad overview of what hydrogen demand might look like in three scenarios: one in which hydrogen technology and deployment is aggressively pursued by policymakers and costs continue to fall, one in which the exact opposite occurs, and one in the middle. Our numbers are not intended to be forecasts, but rather serve to highlight the significant uncertainty surrounding future hydrogen demand[8].

The evolution of competing or complementary decarbonisation options, including energy efficiency, biomass, electrification and carbon capture, will be significant for determining the role or niche for hydrogen. Hydrogen therefore cannot be considered in isolation but rather in combination with the development of others fuels and energy carriers within complex energy systems (Hanley *et al*, 2017).

Our assessment of hydrogen demand focuses on three broad sectors: transport (section 3.1), industrial applications (3.2) and residential heating (3.3). We also discuss the role hydrogen may play in the power sector (3.4). Table 2 provides an overview.

8 Our calculations are predominantly built on interpretations of the European Commission's 'Clean Planet for all' strategy (European Commission, 2018). Additional sources are used to complement our analysis in many cases. A footnote below each set of numbers briefly explains the underlying calculations.

Table 2: Sector scorecard

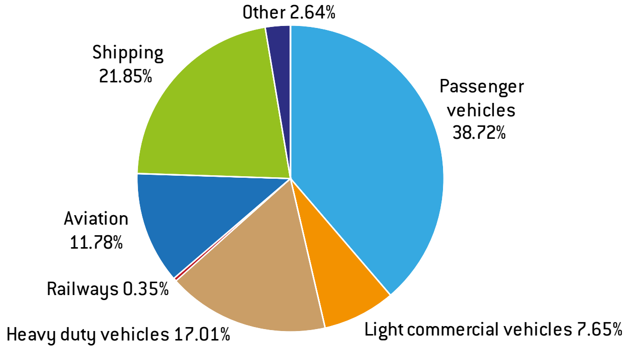
Sector	Emissions (% of EU total)	Hydrogen potential	Note
Ammonia & methanol	14%*	★★★★★	Already using hydrogen produced from natural gas/ industry by-product
Oil refining	2%	★★★★	Already using hydrogen produced from natural gas/ industry by-product
Steelmaking	4%	★★★★★	High potential to replace coal
Passenger vehicles	12%	★	Electric vehicles hold first-mover advantage in low carbon market
Light commercial vehicles	2%	★★	Electric vehicles likely to be strong competitors
Heavy duty vehicles	5%	★★★	Hydrogen more suited to heavier vehicles
Shipping	7%	★★★★	Potential additional demand via use as ammonia
Aviation	4%	★★★	Synthetic fuels; fuel cells
Residential heating	12%	★★	Competing with electricity

Source: Bruegel. Note: *emissions include all chemical sector, not only ammonia and methanol.

3.1 Transport

There are multiple options for hydrogen consumption in the road, rail, maritime and air transport. Pure hydrogen can be consumed directly through a fuel cell to produce electricity, or combusted. Alternatively, hydrogen can be transformed into ammonia before use in a fuel cell or by combustion. Finally, hydrogen can also be used as a building block for renewable synthetic fuels (e-fuels).

Figure 5: GHG emissions share in transport sector



Source: Bruegel.

Transport: Road

Passenger vehicles

- Hydrogen potential: ★
- Upper demand: 140 TWh. Medium demand: 50TWh. Lower demand: 0 TWh[9]
- 12 percent of EU greenhouse gas emissions

In road transport, hydrogen faces direct competition from electricity. Increasingly, the decarbonised future of passenger vehicles looks to be one of battery electric vehicles (BEVs). The price of batteries has rapidly dropped while range per charge is increasing. As a result, the global stock of fuel cell (hydrogen) vehicles is just 11,200 compared to more than 5 million BEVs (IEA, 2019). BEVs now enjoy a first-mover advantage as the conventional low-carbon passenger vehicle. They attract significantly more government and private-sector funding, particularly for charging infrastructure.

Nonetheless, there may be some scope for hydrogen if limitations arise because of raw material shortages, technological limitations of batteries or excess strains on electricity grids arising from too many poorly managed BEVs. Moreover, certain companies (Hyundai, Honda) are still actively developing fuel-cell electric vehicles (FCEV), ie hydrogen passenger vehicles. As markets grow and prices decrease, it is possible that FCEVs will one day compete more seriously with BEVs. Large-scale deployment of hydrogen refuelling networks would be fundamental to this but these currently still face the problem that while FCEV take-up is low, investment in refuelling networks is not attractive. As other economic sectors begin to demand more hydrogen, the roll-out of hydrogen refuelling networks may become economically more attractive.

Hydrogen offers quicker refuelling than battery charging, making it potentially more suited to vehicles in constant use, such as taxis and buses.

Heavy-duty vehicles

- Hydrogen potential: ★★★
- Upper demand: 200 TWh. Medium demand: 120 TWh. Lower demand: 10 TWh[10]
- 5.2 percent of EU greenhouse gas emissions (including buses)

Hydrogen appears to have greater potential for the heavy-duty road transport sector because hydrogen is able to store more energy in a smaller space and at lower weight than a lithium-ion battery. A challenge for manufacturers of battery electric vehicles has been producing batteries which contain sufficient energy but are not too heavy. For example, to provide the same range as a 1000 litre diesel truck, the battery of an electric truck would have to weigh about 14 tonnes. As the capacity and range of lithium batteries has expanded, this problem is gradually being overcome for small, passenger vehicles. However, hydrogen fuel cells could be deployed in heavier vehicles for which greater range and higher power output are required.

In this market segment, hydrogen would compete against biofuels and the use of electrically-derived fuels (via hydrogen). The speed of battery improvements has been rapid so far, and it is still very possible that innovations will allow battery-driven electrification to dominate heavy-duty transport. Overhead transmission lines may also play a limited role.

The most optimistic EU 2050 scenarios see approximately a 15 percent share of hydrogen

9 Figures estimated using the growth rate in passenger vehicles assumed by European Commission (2018). Upper demand based on 15 percent of the vehicle stock in 2050 being hydrogen fuel cell, 5 percent for medium, and 0 percent for lower.

10 Figures estimated using the growth rate in heavy duty trucks to 2050 from European Commission (2018). Upper bound assumes 25 percent hydrogen fuel cell composition of 2050 heavy duty fleet, medium and lower bounds assume 15 percent and 1 percent respectively.

FCEVs in the heavy goods vehicle stock (European Commission, 2018). Least optimistic scenarios would see 0-3 percent FCEV deployment. Some additional indirect hydrogen demand might occur through electrically derived fuels.

Light-commercial vehicles

- Hydrogen potential: ★★
- Upper demand: 60 TWh. Medium: 15 TWh. Lower: 0 TWh[11]
- 2.3 percent of EU greenhouse gas emissions

Vans and light commercial vehicles occupy the middle ground between passenger vehicles and heavy-duty vehicles. They tend to be slightly larger than passenger vehicles, giving hydrogen an advantage because of its higher energy density, but not comparable to heavy-duty vehicles, meaning it is still very possible that this market will be dominated by BEVs. Currently, over 90 percent of light commercial vehicles in the EU are diesels (European Commission, 2018). The deployment of hydrogen fuel cells in this sector may likely depend on the initial success of hydrogen fuel cell deployment elsewhere (particularly in heavy-duty vehicles). However, similarly to passenger vehicles, current market dynamics would still suggest that BEVs will dominate this market.

Transport: Rail

- Hydrogen potential: ★
- Demand: likely to be very close to zero
- 0.11 percent of EU greenhouse gas emissions

The strongest decarbonisation opportunities are in electrifying rail tracks, shifting away from diesel consumption. Electrifying tracks implies significant upfront fixed costs. Tracks electrified so far are those which are the most heavily used in order to increase the ratio of returns to a fixed investment. For less-used tracks, the returns are not large enough to justify the significant upfront capital costs of electrification. On these tracks, hydrogen fuel cells are an attractive option (IEA, 2019).

The potential scope is still relatively small as approximately 50 percent of European tracks have already been electrified (Donat, 2020). Take up of hydrogen for trains on non-electrified tracks can be aided by falls in the costs of fuel cells, driven by deployment elsewhere. Battery electric trains are another option.

Overall, rail is not likely to be a leading candidate sector for large volumes of hydrogen consumption.

Transport: Shipping

- Hydrogen potential: ★★★★
- Upper demand: 120 TWh. Middle demand: 70 TWh. Lower demand: 20 TWh[12]
- 6.6 percent of EU greenhouse gas emissions

The maritime-fuel mix in the EU and globally is dominated by heavy fuel oil. Policy restrictions on sulphur emissions and planned controls on greenhouse gas emissions mark an attempt to move beyond heavy fuel oil. The European Commission is considering including shipping in the EU emissions trading system.

11 Figures estimated using the growth rates in light commercial figures to 2050 from European Commission (2018). Upper bound assumes 20 percent hydrogen fuel cell composition for 2050 light-duty fleet, medium and lower bounds assume 5 percent and 0 percent respectively.

12 Figures estimated on the basis of hydrogen-optimistic and hydrogen-pessimistic scenarios for final energy demand in the shipping sector from European Commission (2018). These figures exclude indirect demand for hydrogen that would arise if ammonia were used as a fuel.

Hydrogen fuel cells may work for short-distance light shipping, for which power requirements are not too large. This is likely to be in competition with battery electric ships. Liquefied hydrogen, synthetic fuels derived from hydrogen and ammonia (Middlehurst, 2020), have greater potential in terms of decarbonising longer distance shipping. Like hydrogen, ammonia can be used to produce energy either by combustion within an internal combustion engine, or by producing electricity through a fuel cell. Biofuels are likely to be another competitor for hydrogen in the maritime sector.

A challenge will be to transform bunkering, or fuelling, facilities, which currently store heavy fuel oils, so they can store hydrogen or hydrogen-derived fuels. Here, a global coordination problem arises as ships must refuel in multiple locations, normally in different countries. For this reason, it is quite likely that one or two fuels will become dominant. Hydrogen might be boosted by other uses in port operations. Forklift trucks are already a big adopter of hydrogen, with 25,000 deployed globally, for example. Port hydrogen storage and distribution infrastructure will become economically more efficient with multiple end-use cases.

Transport: Aviation

- Hydrogen potential: ★★★
- Upper demand: 340 TWh. Middle demand: 180 TWh. Lower demand: 0 TWh[13]
- 3.60 percent of EU greenhouse gas emissions

For short-distance flights, electricity and pure hydrogen could make a significant contribution

For short-distance flights of less than 3,000 kilometres (encompassing most European flights; Madrid to Helsinki is about 2950km, for example), electricity and pure hydrogen could make a significant contribution. This may be through battery or fuel cell (hydrogen) electric planes, or through direct combustion of hydrogen. Hybrid options, combining the two (electricity and hydrogen combustion) are also possible.

Airbus has released three concept designs for hydrogen planes which they state could enter service by 2035 (Airbus, 2020). The proposed planes are of a hybrid nature, combusting hydrogen in modified gas-turbines and producing electricity through fuel cells.

Longer distance flights require fuels with higher energy densities. Advanced biofuels and synthetic fuels[14] derived from hydrogen are the most promising decarbonisation options. Synthetic jet fuel can be a drop-in replacement for current jet fuel. However, options are today far too expensive[15]. Significant policy support and cost reductions would be required for synthetic fuels to be a realistic decarbonisation option.

For longer distance flights, the evolution of biofuels will be a key determinant for the potential of hydrogen fuels. Biofuel production is constrained by land availability[16] and any constraints on biofuel production will provide a stimulus for investment into hydrogen. A further influencing factor will be the extent to which biofuels are demanded by other economic sectors.

Therefore, there are two separate considerations for future hydrogen demand in aviation: directly through use in a fuel cell/combustion to power short-distance flights, or indirectly producing synthetic jet fuels which are then combusted during flight. We estimate an upper bound of 210 TWh of direct hydrogen use in aviation, and 130 TWh indirect hydrogen use for

13 Total energy demand for aviation sector in EU taken from European Commission (2018). Upper demand assumes 30 percent of demand met by direct hydrogen (ie fuel cell + combustion). Of the remaining 70 percent, jet fuel or equivalent substitutes are used. Of this demand, 20 percent is assumed to be met by synthetic fuel production from hydrogen. Lower demand is zero in the case that hydrogen technology does not develop. Medium is midpoint.

14 Synthetic fuel broadly refers to the concept of a chemical fuel synthesis in which hydrogen is reacted with carbon from carbon dioxide in order to produce hydrocarbons with a significant commercial value (eg methane). When hydrogen is produced from green electrolysis and carbon dioxide is captured from the air, this can theoretically be a zero carbon emission fuel.

15 The implied mitigation cost of using power-to-liquid to produce synthetic jet fuel would be in the order of €800/tonne CO2 (Pavlenko *et al*, 2019).

16 Biofuels from seaweed could address this issue but are not yet commercially proven (Bellona Europa, 2020).

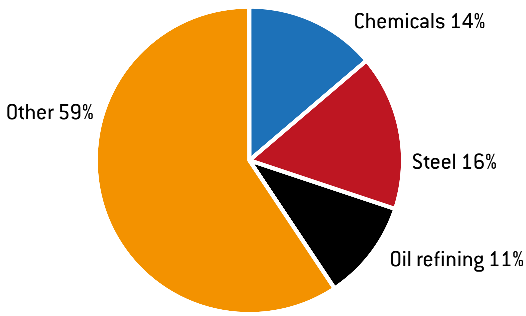
producing synthetic fuels.

However, aviation remains firmly in the hard-to-decarbonise box, with technologies at a very immature stage of development. It will take many years of research and development before the potential of hydrogen relative to alternatives is clarified. Moreover, as one of the hardest sectors to decarbonise, aviation is a strong contender for residual emissions in a net-zero 2050 scenario that involves significant use of negative emissions technologies. Aviation may therefore to some extent carry on burning conventional fossil fuels and emitting greenhouse gases.

3.2 Industry

Currently, over 90 percent of hydrogen produced in Europe is used as a feedstock in oil refining, ammonia and methanol production (Cihlar *et al*, 2020). The possibility of substituting hydrogen for fossil fuels used in steel production is one of the most commonly discussed future uses for hydrogen. These four sectors together account for up to 41 percent of the EU's industrial emissions[17].

Figure 6: EU industrial greenhouse gas emissions



Source: Bruegel.

Chemical sector: ammonia and methanol

- 3.2 percent of EU greenhouse gas emissions[18]

The ammonia and methanol sectors both require hydrogen as a feedstock. The most convenient and cost-effective source is fossil-fuel derived hydrogen.

Ammonia production

- Hydrogen potential: ★★★★★
- Upper demand: 240 TWh. Medium: 160 TWh. Lower: 100 TWh[19]
- 2015 demand: 129TWh

Over 80 percent of ammonia produced worldwide is for the manufacture of fertilisers (Bazzanella and Ausfelder, 2017). Other uses are for nitric acid, pharmaceuticals and cleaning products.

In Europe, natural gas is the most important feedstock. Hydrogen is extracted from natural gas (methane) before being combined with nitrogen from the air to produce ammonia, or NH3. Green hydrogen would therefore be able to directly reduce emissions from ammonia

17 Up to 41 percent with chemical sector emissions used to represent methanol and ammonia.

18 For the whole chemical sector, not just ammonia and methanol.

19 Based on the assumption of a 178 kilogramme hydrogen requirement per tonne of ammonia. The variation arises from different final demands for ammonia in the EU in 2050.

production by eliminating the need for production of hydrogen from methane[20]. Such green ammonia projects are already underway[21].

Europe currently produces 17 million tonnes of ammonia annually and the future evolution of demand is uncertain. As the global population increases, demand for ammonia-based fertilisers will increase; food production must become more efficient to feed an increasing number of mouths from the same amount of land. However, public policy may drive out ammonia in favour of biological fertilisers or higher levels of organic production. The EU in 2019 updated fertiliser rules to promote fertilisers based on organic materials rather than chemicals[22].

Our analysis is based on traditional uses of ammonia, but ammonia demand could rise significantly if ammonia becomes a significant future energy carrier. Ammonia could be a preferable option for transporting the energy contained in a hydrogen atom (ammonia's physical properties make it easier to transport than hydrogen). Ammonia could help in transporting energy from areas of renewable energy abundance to areas of demand. Moreover, non-traditional demands for ammonia may arise in shipping (section 3.1) and potentially even in the power sector[23]. Such a scenario would significantly increase hydrogen demand for ammonia production.

Methanol production

- Hydrogen potential: ★★★★★
- Upper demand: 30TWh. Medium demand: 25TWh. Lower demand: 15TWh[24]
- 2015 demand: 27 TWh

Similarly to ammonia, demand for hydrogen in methanol production is predominantly met by hydrogen from methane. The production of green hydrogen would reduce demand for hydrogen from natural gas and its significant carbon emissions.

Currently, EU methanol production (1.5Mt/annum) as a share of global production is much lower than for ammonia. Assuming similar trends, final demand for hydrogen in this sector is likely to be significantly lower than in the ammonia sector within the EU.

Oil refining

- Hydrogen potential: ★★★★
- Upper demand: 110TWh. Medium demand: 90TWh. Lower demand: 50TWh[25]
- 2015 demand: 153 TWh
- 2.4 percent of EU greenhouse gas emissions

A major use of hydrogen today is in oil refining: turning crude oil into commercially attractive end-use products. Hydrogen is used in hydrotreating and hydrocracking. Hydrotreating refers to the removal of sulphur impurities from crude oil, necessary because sulphur is an air pollutant. Hydrocracking is used to transform heavier residual oils into lighter and more commercially attractive fuels.

20 Production of hydrogen from methane emits 1.83 tonnes of CO2 per tonne of ammonia (Bazzanella and Ausfelder, 2017).

21 For example, a 100MW wind-powered renewable hydrogen production plant in the Netherlands developed by power company Ørsted and fertiliser company Yara (Durakovic, 2020).

22 See https://www.consilium.europa.eu/en/press/press-releases/2019/05/21/eu-adopts-new-rules-on-fertilisers/.

23 Ammonia can be combusted to produce electricity. On a small scale, it is currently co-fired in coal plants to produce electricity with lower emissions.

24 Based on assumption of 189 kilogrammes hydrogen per tonne of methanol. Variation arises from differences in EU final methanol demand in 2050.

25 Our estimations first take IEA trends for a slight decrease in hydrogen requirements in oil refining from 2020 to 2030 while assuming constant demand for oil refining. The scenarios then differ depending on assumptions on the decrease in demand for oil refining.

Future demand for hydrogen in this sector will be determined by future demand for crude oil products, which in Europe is set to decrease. Meanwhile, sulphur restrictions are progressively being tightened, increasing the hydrogen demand per barrel of crude oil[26]. Ironically, sulphur restrictions on crude oil products such as jet fuel have in recent years likely increased the sector's greenhouse emissions because of the current carbon intensity of hydrogen (Catalá *et al*, 2013, Figure 4.5.5). In 2050, there will likely still be demand in the oil refining sector because of the use of hydrocarbons in certain chemical products.

Steelmaking

- Hydrogen potential: ★★★★★
- Upper range: 240TWh. Middle range: 150TWh. Lower range: 100TWh[27]
- 3.8 percent of EU greenhouse gas emissions

The EU produces 177 million tonnes of steel a year, 11 percent of global output[28]. Significant emissions are associated with the steel sector and hydrogen is widely regarded as fundamental to decarbonising the sector.

Most steelmaking greenhouse gas emissions are associated with the turning iron ore into iron prior to its processing into steel. Steel can be produced in blast oxygen furnaces (BOF) (60 percent of EU production; European Commission, 2018) and electric arc furnaces (EAF). The BOF route produces steel using coal and has little future in a decarbonised world, though efforts are being made to reduce emissions by improving efficiency, replacing some coal with hydrogen and retrofitting plants with carbon capture technology. However, unless carbon capture can be done at levels of emissions far above capabilities today, there will always be significant emissions associated with BOF.

Decarbonisation of steel production therefore relies on switching to the EAF (currently 40 percent of EU production). Here, the primary energy input is electricity[29], making green steel possible if the electricity is decarbonised. Two different feedstocks can be used with EAF: scrap steel and direct reduced iron (DRI), or a combination.

Globally, scrap steel contributes to about 25 percent of steel production. Increasing the use of scrap steel would be a welcome shift toward the circular economy[30], but is limited by availability of high-quality scrap[31]. Meanwhile, producing DRI for use in EAF involves reacting iron ore with a reducing agent, currently a mixture of hydrogen and carbon monoxide. This is already a technologically proven route, with deployment particularly in the Middle East where industry has access to low-cost natural gas, which is used for producing the stream of hydrogen and carbon gases for reduction.

All major European steelmakers are currently building or testing hydrogen-based reduction for use in EAF[32]. The target is to use pure hydrogen rather than a hydrogen/carbon mixture for reduction of iron ore. Using both scrap steel and DRI produced using hydrogen in electric arc furnaces is considered the most viable decarbonisation option for the sector within the EU (Hoffmann *et al*, 2020). A related question is whether the move to DRI-EAF

26 See for example the International Maritime Organisation's IMO 2020 rule: https://www.imo.org/en/MediaCentre/HotTopics/Pages/Sulphur-2020.aspx.

27 Demand assumed constant at today's level. Upper assumes all demand met from electric arc furnaces (EAF) with 60 percent direct reduced iron (DRI)/40 percent scrap steel feedstock. Lower assumes 50 percent EAF, and feedstock 50 percent DRI/50 percent scrap steel. Medium assumes 75 percent EAF and feedstock of 50 percent DRI/50 percent scrap steel.

28 See https://ec.europa.eu/growth/sectors/raw-materials/industries/metals/steel_en.

29 Electric arc furnaces can also be rapidly started and stopped. A shift in steel production towards electricity could therefore have positive spillover effects for demand response in electricity grids with lots of variable renewable power.

30 As well as removing the majority of emissions which are associated with the reduction of iron ore.

31 Recycled steel can be contaminated with other elements, most commonly copper. This reduces the quality of steel.

32 HYBRIT in Sweden is a well-known example. See https://www.ssab.com/company/sustainability/sustainable-operations/hybrit.

will affect the location of steel production from close to coal/iron resources to close to cheap green-energy resources.

One issue is the long lifespan of steel plants – approximately 35 years. The production of steel through DRI-EAF using hydrogen is not yet economically mature. However the industry must be wary of locking in any further BOF capacity, with such facilities likely to become stranded assets by 2050.

3.3 Residential heating

- Hydrogen potential: ★★
- Upper demand: 600 TWh. Medium demand: 300 TWh. Lower demand: 0 TWh[33]
- 12.5 percent of EU greenhouse gas emissions

Natural gas is currently the most common primary fuel used for household heating in the EU, accounting for 44 percent of demand. Coal, oil, and biomass are the other significant contributors (Bertelsen and Vad Mathiesen, 2020).

Energy efficiency is the main tool for ensuring decarbonisation of the buildings sector. The EU's long-term roadmap sees energy demand for residential heat halving in a baseline scenario (European Commission, 2018, Figure 39). Demand reductions will be achieved through a combination of rules for new build and existing households. From 2021, new buildings must comply with requirements in the Energy Performance of Buildings Directive 2010/31/EU: new buildings must be nearly zero energy consumption. Old buildings must be renovated, and heating demand reduced through better insulation. The EU's 2020 Renovation Wave strategy is intended to address exactly this issue[34].

Domestic heating can also become more electrified. Electrically powered heat pumps, with an efficiency of 300 percent, are able to draw three times more heat energy from outside air than they consume in terms of electric energy. Currently, the share of electricity in final residential heating demand is approximately 5 percent but European Commission scenarios forecast a growth in this share to between 22 percent and 44 percent by 2050 (European Commission, 2018, Figure 43).

Nonetheless, as a temporary solution, blending natural gas with hydrogen in gas grids is being discussed. Technically, this can be done up to a certain proportion (roughly 5 percent to 20 percent). In the short run, the blending of hydrogen into gas grids allows for incremental reductions in emissions while creating an early demand market for green hydrogen.

To achieve concentrations of hydrogen in gas grids above 20 percent, pipes and grid appliances must be retrofitted. This is not an impossible task; grids in the United Kingdom were retrofitted in the 1960s to move away from town gas (a mixture with a high hydrogen concentration) to natural gas. Switching a gas distribution grid to hydrogen would be organised top-down and would require less significant investments on the user side to decarbonise residential heating, while moving to electric heat pumps will in principle be more efficient and allow for gradual switching of users at their convenience. But it will be more difficult to push individual users to make the necessary substantial investments – one might consider this in light of the difficulties faced with smart meter roll-outs across Europe[35]. Moreover, the required strengthening of electricity distribution grids would also have to be financed.

Under a scenario in which electrification is pursued as the primary residential heat-

33 Based on modelling results from European Commission (2018). Upper demand is taken from the H2 scenario – this scenario achieved an 80 percent reduction in emissions. We assumed a slightly increased hydrogen demand to reach a 100 percent reduction. Medium and lower linearly extrapolated to zero.

34 See https://ec.europa.eu/energy/topics/energy-efficiency/energy-efficient-buildings/renovation-wave_en.

35 In 2014, it was estimated that the penetration of electricity smart meters in the EU in 2020 would be 72 percent. Most recent estimates suggest that the actual figure is about 43 percent. Lack of consumer acceptance, often for privacy reasons, has been a main reason for delay (Tounquet and Alaton, 2020). While heat pumps should not present privacy issues, the example clearly illustrates the challenges associated with a policy that requires the agreement of individual households.

ing technology, hydrogen may still play a complementary role. Decentralised provision of hydrogen (ie gas bottles) could supplement residential heating on the coldest days to prevent excessive strain on local electricity distribution grids.

A final option involves keeping the natural gas network much as it is today but injecting biomethane[36] or synthetic methane produced by combining hydrogen with carbon dioxide. An obvious advantage is minimal disruption to the grid. However current levels of supply of biogas fall far short of demand, and synthetic methane is an inefficient source of energy and is very expensive.

3.4 Hydrogen as an enabler of renewable electricity deployment

In addition to deployment in end-use sectors, hydrogen could be used for energy storage, enabling the integration of increasing shares of variable renewable generation into electricity systems.

Historically, electricity grids have operated on the basis of volatile aggregate demand from end-users being met by a mix of inflexible base-load (nuclear, lignite, run-of-river) and peak-load power that is dispatched on demand (for example gas or hard coal), with relatively little storage. Increased adoption of variable renewable electricity sources is changing this model. A challenge for grid operators is to maximise the uptake of renewable electricity that is produced when the sun is shining and the wind blowing. A number of options, beyond the scope of this Policy Contribution, are under consideration, including the use of hydrogen produced from electrolysis.

Short-term flexible demand

Hydrogen production via electrolysis could be increased during times of excessive renewable power generation and reduced when supply is weak, allowing more efficient balancing of the electricity market. Kopp *et al* (2017) showed that already in 2016, a 6 MW electrolyser in Mainz, Germany was deployed with economic benefit to the German control reserve market.

Whether electrolysers can be competitive as providers of grid-balancing services will depend on technological and regulatory developments in the next few years. In particular, battery storage systems that already feature much lower storage losses than hydrogen will likely see their capacity costs drop dramatically as more batteries are produced and deployed. They may therefore be better suited than electrolysis to managing intra-daily or even intra-weekly fluctuations on electricity grids.

Long-term seasonal storage

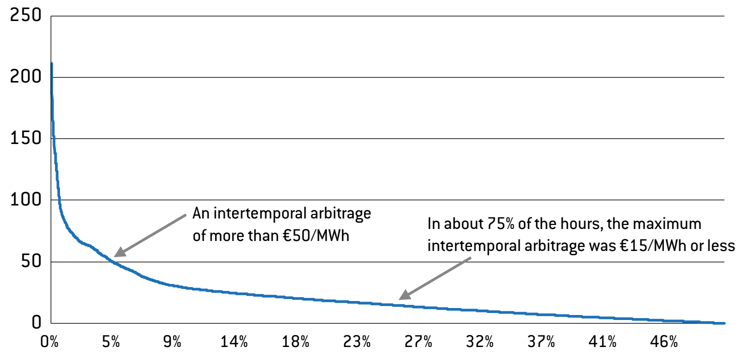
Hydrogen could be a more useful option for managing fluctuations in renewable electricity produced in different seasons. Hydrogen could be produced during months of excess renewable electricity production, stored geologically, and then converted back into electricity during months of lower renewable electricity supply. Compared to batteries, hydrogen is a more plausible solution for seasonal storage because investment costs are almost independent of storage volume[37] and 'self-discharge' is low (Parra *et al*, 2019).

From an economically efficient perspective, whether hydrogen emerges as a seasonal storage mechanism will depend on the relationship between seasonal price differentials and the capital costs of deploying electrolysers along with storage. German electricity price differentials show that currently only for 5 percent of the time does the price differential (arbitrage gain) exceed €50/MWh. The evolution of this potential for arbitrage gain will inter alia depend on the deployment of renewable electricity generation sources and on the deployment of flexible demand side resources.

36 Refined from biogas, which is produced through anaerobic digestion of waste or organic matter from a variety of sources.

37 Most of the investment cost is related to the capacity (ie the MW) of the appliances that transform electricity into hydrogen and back – while the size of the storage tanks/aquifers (ie the MWh) does not drive cost that much.

Figure 7: Price differential, lowest vs highest hourly prices in Germany, 2019

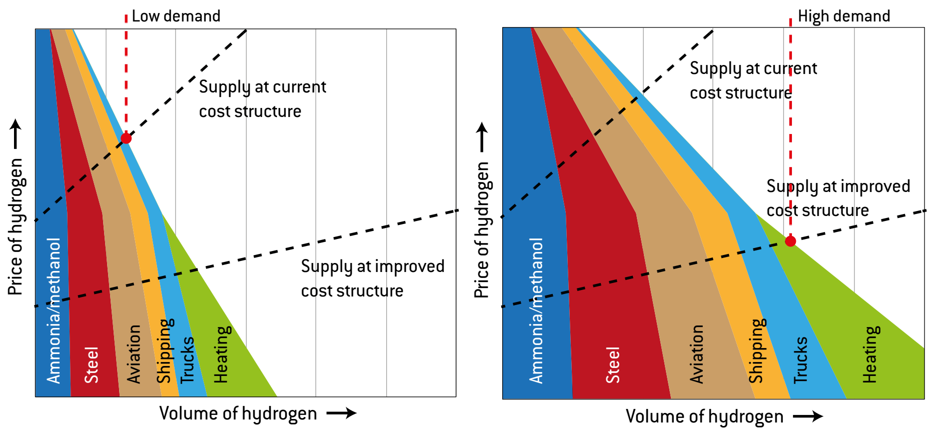


Source: Bruegel based on SMARD.

4 Overview of market dynamics

The current cost structure of hydrogen is based on its production from natural gas (methane). But, as we have discussed, this supply is expected to be considerably transformed. The market consensus is that the price of low-carbon hydrogen will decrease over the coming years, largely driven by falling electrolyser costs (which can be reinforced by deployment policies that allow economies of scale and learning). The extent of this cost decrease will determine the competitiveness of low-carbon hydrogen for each end-use sector (Figure 8).

Figure 8: Stylised hydrogen demand scenarios



Source: Bruegel. Note: left panel shows a scenario with limited technological/commercial development on the demand side; right panel shows a scenario with significant breakthrough in all demand sectors.

A further fundamental driver of supply costs will be the cost of fuel inputs – electricity in the case of electrolysis. Expectations are that, unless there are breakthroughs in terms of more flexible power demand/storage, there might be more hours with very high and very low prices (Bossmann *et al*, 2018). Thus, there is potential for hydrogen costs to be further lowered by running electrolysers only in hours when – thanks to abundant power from renewables and/or low demand – electricity is particularly cheap. However, while the investment cost of electrolysers remains high, they will have to run most of the year to justify their fixed costs. Only when the fixed costs of electrolysers reduce enough will their use be economic in part-load. But then they will start to push up electricity prices during exactly those hours where it is economic to operate them. This will make additional renewables investments economically viable and an equilibrium could develop. Electrolyser capacity in this equilibrium will be determined not only by the cost of renewables and electrolysers, but also by the cost of competing flexibility providers (eg batteries, demand-response). Thus, if batteries continue their rapid pace of technological advancement, and/or innovation sees electricity demand become increasingly flexible, it is still possible that the capital costs of electrolysers will be too high to justify their part-load operation.

Non-EU countries are also investing in hydrogen production capacity. In some cases, this involves cooperation with Europe, such as between Germany and Morocco (BMZ, 2020). In other cases there is no European cooperation and hydrogen will potentially be traded on international markets. The ability of third countries to produce hydrogen under more favourable conditions may exert downward pressure on European prices, although transport costs would have to be factored in, as discussed in section 2.

The evolution of hydrogen demand within Europe is highly uncertain (section 3). But whatever happens, a certain level of hydrogen demand is almost certain to remain, the extent of which will depend on the demand for the end products: ammonia, methanol, crude oil-derived products. In other sectors, demand for hydrogen will depend if hydrogen-utilising technologies reach commercial maturity.

5 Policy options

The future prospects of hydrogen are highly uncertain. Currently, it is a chemical feedstock but significant breakthroughs in production and end use could mean hydrogen might even contribute 20 percent of the EU's final energy demand in 2050. The challenge for policymakers today is to assess the correct level and type of policy support in the context of this uncertainty. We conclude with a discussion of some of the policy measures that could support hydrogen deployment currently being debated.

Meaningful price on all greenhouse gas emissions

Tightening/extending the EU emissions trading system and re-thinking the design of energy taxation systems

Higher prices on the use of fossil fuels help the competitiveness of all low-carbon technologies relative to fossil-fuel alternatives. In 2021 the European Commission will propose to extend and tighten the EU emissions trading system (ETS) in line with tougher emission reduction targets. Addressing the current taxation discrepancy between electricity and natural gas prices would be another no-regret option. From a carbon emissions standpoint, the European taxation system currently biases consumption away from electricity and toward natural gas[38]. The European Commission can address such discrepancies by reforming the EU Energy Taxation Directive (2003/96/EC), which is also scheduled for 2021.

Supporting low-carbon hydrogen production

State support for the production of hydrogen with low carbon emissions

We classify this as a no-regret policy option. Decarbonising the production of current hydrogen demand would already avoid approximately 100 Mt of CO_2 emissions in the EU per year. The wide range of sectors which could potentially use clean hydrogen suggests that the benefits of decarbonising hydrogen production are likely to exceed those from current demand only.

38 This DG ENER factsheet shows the discrepancies in taxation rates: https://ec.europa.eu/energy/sites/ener/files/qmv_factsheet_on_taxes.pdf.

Moreover, until a low-carbon hydrogen source at scale is secured for Europe, there is limited value in stimulating a massive ramp up in additional hydrogen demand, which would be met by carbon-intensive production methods[39]. Supporting low-carbon hydrogen should therefore be a policy priority.

The deployment of a significant volume of electrolysers should be supported to reduce their cost. This could be done using tools that proved successful for wind and solar technology (auctioning of feed-in premia). Policies to support the deployment of renewable electricity generation to fuel growing demand from electrolysers would also be a no-regret option. The deployment of other low-carbon hydrogen production should also be phased in when industry is willing to share some of the remaining technology risk.

From a geopolitical standpoint, developing commercial know-how in technologies used to produce clean hydrogen is likely to make Europe's exports more competitive in a decarbonising world.

Supporting green products

State support for the production of low-carbon products, particularly in markets currently dominated by emissions-intensive production

Focusing public support to the demand for low-carbon products and intermediate goods (such as low-carbon steel) has the advantage of being technologically neutral. Markets would be allowed to decide the most cost-efficient manner for production. Public revenue would be spent only for products for which a clear carbon-emissions reduction has been achieved. This would allow policymakers to adopt a neutral standpoint regarding the applicability of hydrogen technologies, and to avoid public money being spent on projects that eventually do not significantly reduce emissions.

The EU already has a tool for defining low-carbon benchmarks in the ETS product benchmarks[40]. A challenge would be choosing which products to support, and how much to support each product.

One drawback to this solution may be that one or two technologies are over-supported, while other options are ignored. The question then arises of whether the state is able to predict accurately which products and technologies should be supported. This is because an explicit focus on decarbonising one sector prioritises technologies that are suitable for that sector while not necessarily taking into account that support for a different technology may have wider benefits for the rest of the economy. For example, a focus on decarbonising heavy transport today might boost the competitiveness of new fuel cells and hydrogen tanks that then could be used in light vehicles, trains and aircraft, while a focus on decarbonising light vehicles today might instead extend the head start batteries have to all other modes of transportation.

Supporting R&D

Support for hydrogen research and development

Europe invests too little into R&D in general (D'Andria *et al*, 2017). Public support for low-carbon R&D is a no-regret option. However, prioritising support for different areas is more controversial.

Many potential hydrogen applications would benefit from R&D investment. On the supply side, a range of potential production pathways could be explored. Public support for increas-

39 There is an argument that it is still worthwhile pursuing demand cases today and that clean hydrogen supply will eventually 'catch up'. There is clear reason to this argument, but we believe that a clearer route must first be established for the decarbonisation of hydrogen supply within Europe. Supplying the volume of clean hydrogen suggested by our highest demand case would currently be very difficult for Europe.

40 Product benchmarks have been calculated for a range of emission-intensive products under the ETS. This benchmark is based on the average greenhouse gas emissions associated with the best performing 10 percent of installations. They can therefore be thought of as the best-practice emissions associated with production of a particular product.

ing the number of potentially viable decarbonisation options would make the low-carbon transition more resilient (eg if other technologies fail unexpectedly). Increased technology competition is also important to exert pressure on dominant technologies (eg electric vehicles) to invest in innovation based on specific criteria where alternative technologies still have a lead (eg limited range).

There is a strong case for Europe to significantly scale up R&D for all decarbonisation options. But, in a scenario of limited R&D budgets the value of hydrogen R&D must be weighed against R&D in competing technologies or energy carriers.

A consistent and predictable support mechanism at the European level would be beneficial. It could periodically allocate R&D funding to areas that appear most attractive according to decarbonisation criteria and priorities. The mechanism would adapt to technological evolution in order to avoid institutional lock-in[41]. It could take the form of an independent public body, a European Energy Agency, which could provide policy advice to the European Commission and interested member states. For example, future bottlenecks in the shift to a low-carbon economy could be identified as a basis for today's public R&D support. Such a mechanism would help identify which hydrogen technological applications justify public R&D.

Finally, in the context of the current economic crisis, a focus on creating jobs and high multipliers might lead to an underappreciation of the merits of R&D for long-term economic development.

Retrofitting natural gas networks

Public infrastructure investment to adapt the natural gas grid to make it suitable for transporting hydrogen

The natural gas grid constitutes a significant infrastructure asset, capable of holding large volumes of energy. At reasonable cost it could be repurposed for a low-carbon economy.

The necessity of repurposing the gas grid depends upon the size and geographic dispersion of demand clusters. If households are to consume significant volumes of hydrogen, clearly repurposing is necessary and investment should slowly begin. However, it is not clear if household-level hydrogen demand will ever materialise (section 3). Instead, our demand analysis points to the likelihood of relatively significant hydrogen demand emerging in a series of large industrial clusters ('hydrogen valleys') across Europe. In each cluster, hydrogen-using industries (eg ammonia, steel, carbon storage) would co-locate and share the costs of hydrogen production or transmission. Therefore, a planning perspective would not place much importance on building out a hydrogen distribution grid to the scale of anything like that resembling the current natural gas infrastructure. Instead, a few transmission pipelines connecting large demand and supply sources would be the priority investment.

Therefore, while it is technologically possible that hydrogen could satisfy household energy demand, it is not a first-best solution. The challenge in the transition between two network-based systems (eg gas-based heating to electricity-based heating) is, that at one stage in the transition, the incumbent network will lose so many subscribers that its remaining subscribers will bear too much of its fixed cost, leading them to unsubscribe at increasing speed. Such an disorderly transition (which was seen for some central heating networks in eastern Europe) can be inefficient and might need to be publicly managed.

In addition, policymakers should focus short-term planning (5-10 years) and regulatory activity on enabling industry to build the infrastructure necessary for a system of large industrial hydrogen clusters. Decisions over whether to retrofit natural gas grids at a more granular level should be postponed until clearer evidence emerges of the capacity of electrical solutions to fully satisfy household energy demand.

Current market dynamics do not yet suggest that retrofitting natural gas grids to carry hydrogen is a sensible public policy.

41 See Zachmann *et al* (2012) p 99, for further discussion.

Roll-out of hydrogen vehicle charging stations

State support for the deployment of hydrogen vehicle charging stations

Hydrogen vehicle charging stations are an enabling infrastructure. Providing the means to refuel and operate hydrogen vehicles should stimulate private investment in the production and purchase of hydrogen vehicles. Some pilots have already been supported (fewer than 100 in Germany).

However, significant public support for hydrogen charging stations would likely not be sensible. As discussed in section 3, the case for a transition of most transport sectors to hydrogen appears weak when compared to the case for battery electric technology. There is a risk that public support for hydrogen refuelling stations would be at the expense of public support for electric charging stations.

European policymakers should continue to increase the stringency of decarbonisation policies for the transport sector. As discussed, with higher carbon prices or tougher policies, hydrogen solutions may be viable for heavy vehicles. In such a future scenario, private investment could cover the required charging stations (at either end of a trucking route, for example). If private consortia come forward with co-financing options for publicly available hydrogen charging stations, policymakers might consider offering small incentives, but this should not be a landmark policy.

Hydrogen vehicle charging stations are not today a priority for public support.

Certification scheme for low-carbon hydrogen

Developing a system for robust classification of the carbon content for each MWh of hydrogen

Knowing the carbon emissions associated with the production of each MWh of hydrogen will be an issue for future hydrogen consumption. Within Europe, calculations should not be necessary because hydrogen production falls under the ETS, and so carbon emissions are already priced in. But certification may be necessary for certifying the 'greenness' of hydrogen imports.

Designing a robust classification system will be difficult. For electrolysis, this would involve certifying the electricity input. When electricity for electrolysis is taken from the public grid its carbon content is more a matter of definition/accounting, than an objective value[42]. But even certifications of dedicated supplies from renewable electricity often do not pass the additionality test: has new renewable electricity capacity been built exclusively for hydrogen purposes, or has existing or already planned renewable capacity simply been 'assigned' to hydrogen production?

While a difficult task, European policymakers should think about designing a framework for the international trade in clean hydrogen. The extent to which hydrogen will become an internationally traded commodity remains to be seen, but if such a scenario emerges, Europe is likely to be a significant net importer. It would be wise, therefore, to start the conversation about how Europe can be sure its hydrogen imports are low carbon.

Competition policy/regulation holidays

Providing breaks from the rules of competition policy or regulation to encourage targeted investment

Providing some temporary exemptions from strict competition/network regulation rules designed for mature markets can be a tool for encouraging private sector buy-in. Horizontal and vertical coordination are both crucial during the earlier stages of building a new network. For example, initial investments in the production, transmission and consumption of

42 For electrolysis, it would require defining the carbon content of the used electricity and three very different values can be used for each hour in which the electrolyser was used: cleanest power plant; average power plant; dirtiest power plant or last (marginal) power plant required to meet the demand. In the short-term, the last option seems most plausible, but in the longer term, additional demand from electrolysis might be met be increasing supply, potentially from renewable sources.

hydrogen need to be well synchronised. Without the ability to ensure the provisioning of the complementary elements of the hydrogen value chain (through vertical integration or binding agreements), private investment may be discouraged in some areas. There is a coordination problem, with investment into all elements needing to be synchronised because each individual investment (eg an electrolyser) is only worthwhile if all other parts of the new value chain (eg a hydrogen pipeline, storage or steel-plant) also work.

Additionally, regulatory breaks can help encourage breakthrough R&D and investment. This is particularly the case for testing new technologies, such as the correct protocols for using hydrogen in households.

In both cases, such exemptions must be temporary and well targeted so they encourage investment in areas with high benefits.

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